Office of Ratepayer Advocates
California Public Utilities Commission

Risk of Unplanned Retirement and PLEXOS Production Cost Simulation

Order Instituting Rulemaking to
Consider Electric Procurement Policy Refinements
pursuant to the Joint Reliability Plan

Rulemaking 14-02-001

San Francisco, California
October 30, 2014

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I. Executive Summary

The Joint Reliability Plan (JRP) explains that the California Public Utilities Commission (CPUC) and the California Independent System Operator (CAISO) "will seek to minimize the risk of an unexpected (disorderly) resource retirement that result from the resource receiving insufficient revenues to continue operations even when the resource will be needed to meet reliability needs."[1] In order to better understand the risk of unexpected, or unplanned, retirement, the Office of Ratepayer Advocates (ORA) completed the following analysis. First, ORA evaluated the Risk of Unplanned Retirement in order to quantify the magnitude of potential unplanned retirements of existing resources that may be needed in the future to meet flexibility requirements. ORA found that there were nine units potentially at risk of unplanned retirement, comprising approximately 2,412 megawatts (MW) of which 1,389 MW are flexible. Second, ORA conducted a PLEXOS Production Cost Simulation study for the year 2021 to understand the effect on potential resource need of unplanned retirement accounting for 2,412 MW of Net Qualifying Capacity (NQC) and 1,389 MW of Effective Flexible Capacity (EFC). The year 2021 was also selected because that is the first full year following the scheduled retirement of once through cooling (OTC) resources. ORA's two scenarios start with the Trajectory scenario parameters from the 2014 Long Term Procurement Plan (LTPP). The two scenarios are:

1. 2021 Trajectory (Base case scenario) and
2. 2021 Trajectory with units at risk of unplanned retirement accounting for 2,412 MW of NQC and 1,389 MW of EFC (Retirement scenario).

Adjustments are made to the 2024 model provided by CAISO to reflect ORA's understanding of loads and resources in 2021, based on assumptions in the Scenario Tool. The plants potentially at risk of unplanned retirement are then removed from the resource stack. ORA's Risk of Unplanned Retirement analysis and PLEXOS Production Cost Simulation study indicates that meeting system and flexible capacity needs in 2021 would **not** be jeopardized by the unplanned retirement of up to 2,412 MW of NQC and 1,389 MW of EFC.

[1] The Joint Reliability Plan adopted on Nov. 14, 2013, p. 5, available at http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&DocID=81666376

II. Risk of Unplanned Retirement Analysis

On May 2, 2014, the CPUC held a workshop on the JRP. During the workshop, ORA presented its analysis on the risk of unplanned retirement. The analysis found that there are nine units potentially at risk of unplanned retirement, comprising approximately 2,412 MW of which 1,389 MW are flexible. The following comments explain the methodology and assumptions used in ORA's analysis.

Methodology

The risk of retirement analysis sought to quantify the magnitude of potential unplanned retirements of existing resources that may be needed in the future to meet flexibility requirements. ORA's analysis assumes that resources with a lower probability of obtaining a capacity contract, for a certain period of time through 2020, are at greater risk of unplanned retirement than resources that either already have or are likely to receive capacity contracts. It is important to note that if any one of the nine units potentially at risk of unplanned retirement were to actually retire, the probability of the remaining units obtaining capacity contracts would increase because those resources would face less competition. Therefore, it is highly unlikely that all nine units will actually retire due to an inability to obtain capacity contracts.

ORA selected 2020 as the critical cutoff year because (OTC) retirements will occur in 2020 or earlier.[2] It is reasonable to assume that there will be less excess capacity in the market as OTC plants proceed to retire through 2020. Less excess capacity in the market increases the probability that the remaining non-OTC resources will secure capacity contracts because those resources will face less competition. Consequently, it is less likely that those remaining non-OTC resources will retire in an unplanned manner.

In order to understand the magnitude of the potential for unplanned retirements, ORA began its analysis using the Scenario Tool provided in the LTPP Proceeding,[3] because that tool contains all the power plants in California. In addition, the Scenario Tool has the vintage, resource type, and NQC of each of the power plants contained in the CAISO 2014 NQC List.

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[2] This is consistent with the 2014 LTPP Scenario Tool available at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.

[3] See http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.

ORA utilized the CAISO's Effective Flexible Capacity Report[4] to obtain each resource's monthly flexible capacity numbers based on the definition of flexible capacity, as determined in Decision (D.)13-06-024.[5] Beginning with the Scenario Tool's 2014 NQC list, ORA proceeded to identify the resources potentially at risk of unplanned retirement. Table 1 and Figure 1 below show the steps taken by ORA and resulting capacity:

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[4] See http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm.

[5] See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF.

Table 1: Risk of Unplanned Retirement

Risk of Unplanned Retirement	Resource Type	# of MW	# of Units
	Total Capacity in CAISO Territory	**51,228**	**740**
Low	Non-Flexible Units or Non-Thermal Units[6]	18,514	567
N/A	Flexible Units Subject to Once-Through Cooling (OTC) Mandate[7]	11,035	31
N/A	Flexible Units Built in 1982 or Earlier[8]	1,633	16
Low	Flexible Utility-Owned Generation[9]	3,681	17
Low	Flexible Municipally-Owned Generation[10]	1,448	25
Low	Flexible Units in Local Areas[11]	10,512	69
Low	Flexible Units with Capacity Contracts Ending after 2020[12]	472	3
Low	Flexible Competitive Units with Multi-Year Capacity Contracts Ending in 2020 or Earlier[13]	1,521	3
Medium	**Flexible Units at Risk of Unplanned Retirement**[14]	**2,412**	**9**

[6] These are renewable and baseload units. These units have a low risk of retirement because of RPS goals or, in the case of baseload, their place in the resource stack.

[7] 2012 LTPP Scenario Tool v6 assumes all OTC units will retire in 2020 or earlier based on their mandatory compliance dates.

[8] 2012 LTPP Scenario Tool v6 assumes units 40 years or older will retire.

[9] Utility-Owned Flexible Thermal Units built after 1982 are unlikely to retire due to revenue certainty.

[10] Municipally Owned Flexible Thermal Units built after 1982 are unlikely to retire due to revenue certainty.

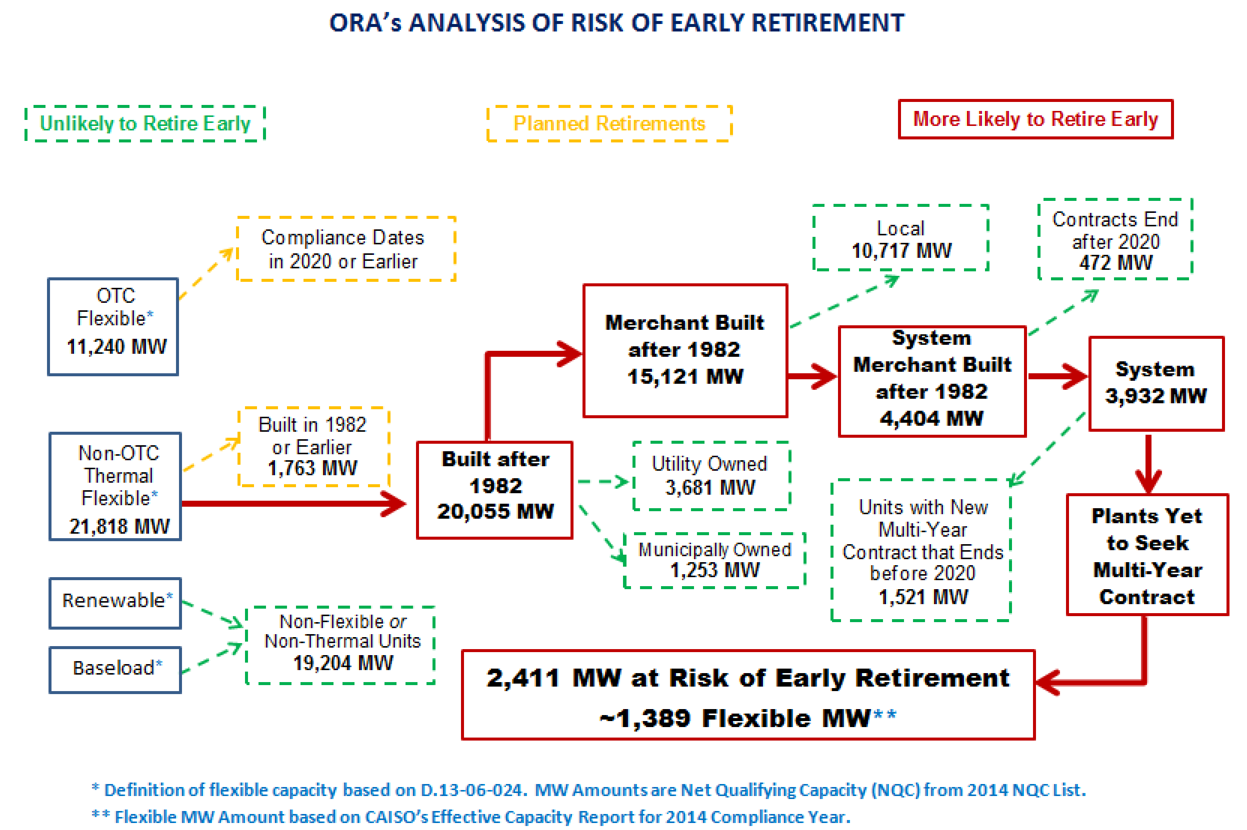
[11] Local resources are unlikely to retire due to the higher local Resource Adequacy (RA) capacity premium which reflects scarcity.

[12] Resources that are under long-term capacity contracts beyond 2020 are unlikely to retire because their contracts expire after OTC-mandated compliance deadlines.

[13] These units successfully bid into previous Requests for Offers (RFOs) and were able to acquire multi-year contracts. With the introduction of flexible capacity requirements, these units are likely to continue to be successful in obtaining RA contracts.

[14] Flexible MW amount is 1,389 MW out of the total 2,412 MW. Approximately 500 MW of the total 2,412 MW are under long-term Power Purchasing Agreements (PPAs) until mid-2020.

Figure 1: Risk of Unplanned Retirement



ORA determined that there are nine units potentially at risk of unplanned retirement accounting for approximately 2,412 MW of NQC and 1,389 MW of EFC. However, this is a worst-case scenario because plants will have the opportunity to earn energy revenues and will have a higher likelihood of obtaining capacity contracts as OTC plants proceed to retire through 2020. This may be sufficient to prevent some units from retiring even if they do not obtain a capacity contract in a certain year. Finally, it is possible that some of the nine facilities listed above have long term capacity contracts with municipally owned utilities and other Load Serving Entities (LSEs) and therefore should not be considered as being potentially at risk of unplanned retirement.[15]

[15] ORA's Risk of Unplanned Retirement analysis does not include capacity contracts held by LSEs other than PG&E, SCE, and SDG&E. Therefore, it is possible that the nine facilities identified above have capacity contracts with other LSEs, including non CPUC-jurisdictional LSEs.

III. PLEXOS Production Simulation Analysis

ORA used the results of its Risk of Unplanned Retirement analysis to conduct a PLEXOS Production Cost Simulation study for year 2021 to understand the effect on potential resource need of unplanned retirement accounting for 2,412 MW of NQC and 1,389 MW of EFC. In the LTPP proceeding, Synapse[16] used the PLEXOS modeling tool[17] to replicate the CAISO's Trajectory scenario run for the twelve months of 2024. For the analysis here, ORA adjusted the model to reflect 2021 and understand the effect on potential resource need if unplanned retirements accounting for 2,412 MW of NQC and 1,389 MW of Effective Flexible Capacity occur.

ORA's two scenarios start with the Trajectory scenario parameters from the 2014 LTPP. As explained in the Attachment to the Planning Assumptions Assigned Commissioner's Ruling (ACR):

> "The Trajectory scenario is the control scenario for resource and infrastructure planning, designed to reflect a modestly conservative future world with little change from existing procurement policies and little change from business as usual practices."[18]

ORA's two scenarios adjust the 2024 model provided by CAISO to reflect ORA's best understanding of loads and resources in 2021, based on assumptions in the Scenario Tool. The two scenarios are:

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[16] Synapse Energy Economics, Inc. (Synapse), is ORA's consultant in the JRP proceeding.

[17] PLEXOS is a detailed hourly production cost model. The analytical structure of PLEXOS (hourly dispatch and associated unit commitment) captures the capability of individual resources (and in the aggregate, system-wide resources) to provide energy required for operating reserve for each hour of the year.

[18] Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in 2014 Long Term Procurement Plan (LTPP) and 2014-2015 California Independent System Operator (CAISO) Transmission Planning Process (TPP) issued May 6, 2014, Attachment, p. 35. Other scenarios, and the order in which the Planning Assumptions ACR indicates they should be studied are: the High Load Scenario ,which explores the impact of higher than expected economic and demographic growth, the High DG [distributed generation] scenario, which explores the implications of promoting high amounts of DG; the 40% [Renewables Portfolio Standard]RPS in 2024 Scenario, which would assess the operational impacts associated with a higher RPS target post-2020, and the Expanded Preferred Resources scenario, which would assess the impact of broadly pursuing higher levels of preferred resources. Attachment, pp. 34-38.

1. 2021 Trajectory (Base case scenario)
2. 2021 Trajectory with the retirement of units at risk of unplanned retirement accounting for 2,412 MW of NQC and 1,389 MW of EFC (Retirement scenario).

Both scenarios incorporate the expected OTC retirements in 2020. The Retirement scenario includes an additional 2,412 MW of retired capacity. Neither scenario includes additional resources authorized in Track 4 of the 2014 LTPP proceeding, or authorized preferred resources from Track 1, which would represent 1,325 MW at a minimum[19], and roughly 2300 MW maximum.[20]

The model provided by CAISO in the 2014 LTPP proceeding was configured for 2024 only. ORA made the following adjustments to accurately reflect energy load and resource situation in 2021:

1. Annual Peak Loads and Annual Energy in CAISO, the rest of California, and the rest of the Western Electricity Coordinating Council (WECC)
2. Installed photovoltaic (PV) capacity
3. Storage resources
4. Demand response resources
5. RPS resources

Loads in CAISO were adjusted based on the 2013 Integrated Energy Policy Report (IEPR) forecast (Form 1.5). No adjustments were made to the hourly pattern. This resulted in annual energy requirements adjusted downwards, ranging from a low of 2.6% (Pacific Gas and Electric (PG&E) Bay) to a high of 3.8% (PG&E Valley) in the CAISO regions.[21] In other words, annual energy requirements were 2.6% lower in 2021 than 2024 in the PG&E Bay Area. Non-CAISO

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[19] In the LTPP proceeding, ORA modeled a scenario with 600 megawatts (MW) of conventional resource (gas-fired gas turbine (GT)) in San Diego Gas & Electric Company (SDG&E)'s service territory area, and 725 MW of preferred resources (550 MW in Southern California Edison Company (SCE) service territory, and 175 MW in SDG&E's service territory) to reflect this minimum level of procurement.

[20] D.14-03-004, pp. 3-4.

[21] PG&E's service territory extends from Eureka in the north to Bakersfield in the south, and from the ocean east to the Sierra Nevada. The PG&E Valley areas in the PLEXOS model represent the northern and eastern portions of this territory, while the PG&E Bay area represents the Greater Bay Area and southern territory.

regions (including the rest of the WECC) were adjusted downwards based on an average of the CAISO adjustment factors of 3.2%.[22]

Behind-the-meter PV resources were adjusted based on the Scenario Tool forecast for 2021 under the Trajectory scenario. These values are based on an IEPR mid load forecast and a mid PV forecast, as developed by Energy Division. The revised values are presented in Table 2.

Table 2
Installed Behind the Meter PV Capacity (MW)

	2021	**2024**
SCE	1228	1564
SDGE	389	534
PGE_VLY	1090	1389
PGE_BAY	842	1072
Total	3549	4559

Storage resources were included in the modeling based on the CPUC's Storage Target Decision (D.13-10-040), which forecasts 1,325 MW of storage resources in 2024.[23] ORA reduced this figure to 828 MW in 2021. The Scenario Tool only provides statewide installed capacity values, so ORA held the proportion of storage resources in PG&E, SCE, and SDG&E constant and adjusted values downwards to reach the 2021 target.

Adjustments to demand response (DR) capacity were small – ORA removed 5MW of DR resources with anticipated installation dates between 2021 and 2024 to reach the value of 2,171 MW, as indicated in the 2014 Scenario Tool. The reduced loads in the 2021 case also resulted in a downward adjustment to RPS requirements. Based on the Scenario Tool and a 33% RPS target in 2024, ORA's changes in load resulted in a reduction of 143MW of renewable resources. 143 MW of wind resources in California were removed to make this adjustment.

[22] 3.2% is a weighted average of the PG&E Valley, PG&E Bay, SDG&E, and SCE load adjustments. This factor was applied to all other balancing areas, both within California and in the rest of WECC.

[23] This 1,325 MW includes 50 MW of storage in SCE authorized in D.13-02-015.

Synapse's results show the projected patterns of capacity "headroom"[24] in 2021 during all hours of the year for the Trajectory scenario as defined in the Attachment to the Planning Assumptions ACR.[25] The Base case scenario shows no shortages in 2021. The Retirement scenario shows shortages on two days in July for a total of four hours, peaking at 1,470 MW on July 19 at 5PM.[26]

Figure 2 shows the hourly pattern of capacity headroom in the CAISO region as reflected by the modeling.[27] This hourly metric is labelled as surplus or shortage. It is the sum of the available CAISO-region capacity, plus the amount of net imports in that hour, minus the CAISO hourly load and associated ancillary service requirements, which include spinning and non-spinning reserve, and load-following and regulation up requirements. This can be represented as:

Available CAISO Capacity + Net Imports - Load + Upward Reserve Requirements = Surplus (or Shortage) in MW for any given hour.

ORA conducted a full 12-month modeling for the 2021 Retirement scenario. ORA presents the results of its 12-month modeling in terms of capacity headroom, which is a measure of resource surplus or shortage. This metric is computed for each hour of the year. A modeled resource surplus exists if there is excess available capacity in any given hour of the year as indicated by the PLEXOS model outputs. A modeled resource shortfall exists if the hourly load plus the ancillary service requirement cannot be met by existing and planned resources and import capacity. Figure 2 below show the pattern of surplus and shortfall hours over the course of 2021 for the Retirement scenario.

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[24] For purposes of these comments, the term "headroom" or "capacity headroom" means a measure of capacity surplus or, when negative in value, shortage or shortfall. Surplus is the measure of additional CAISO available capacity that exists in any given hour after meeting all energy and ancillary service requirements for that hour. Shortage and/or shortfall occurs when the PLEXOS model is required to use a "proxy" resource (i.e., one that is not existing or planned) in order to solve for all energy and ancillary service needs during critical hours.

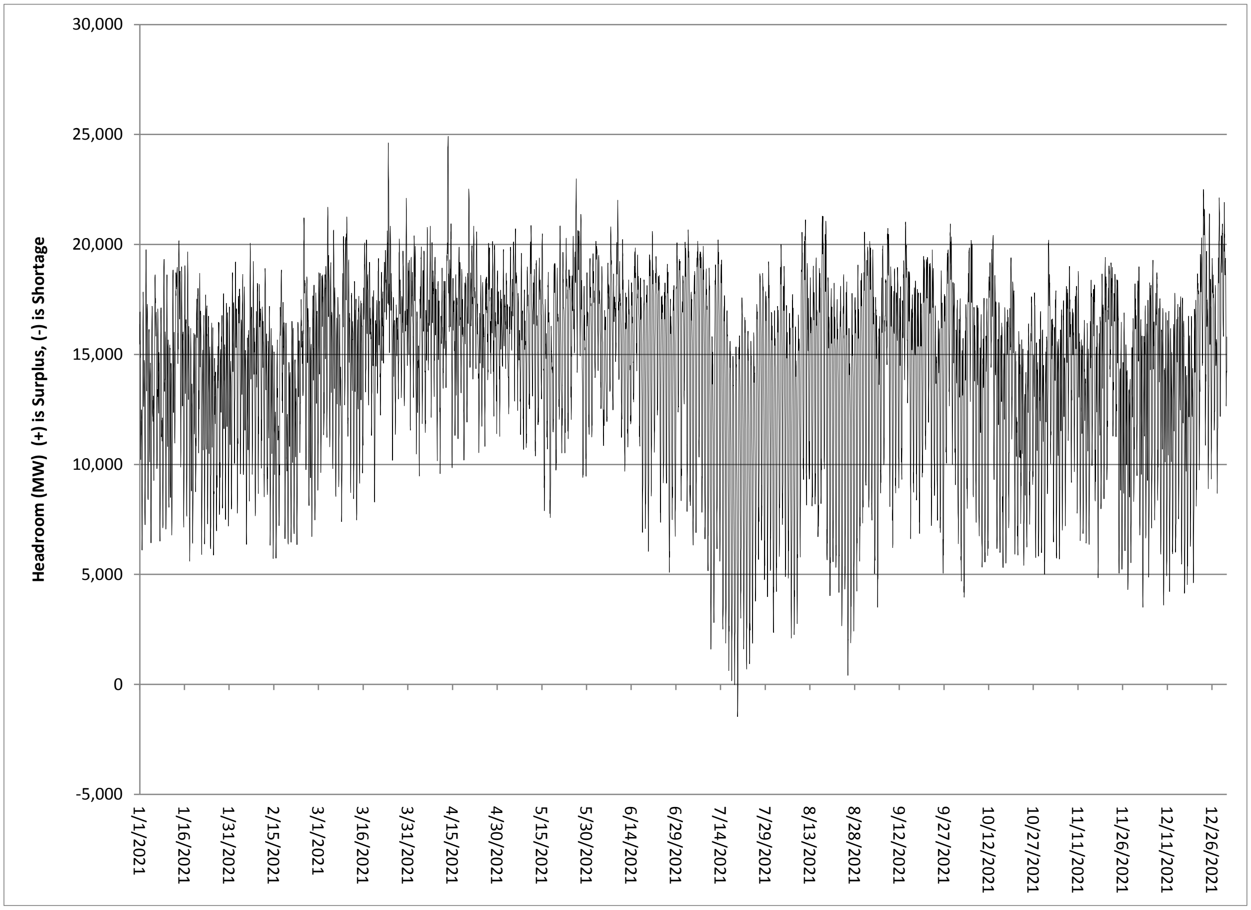
[25] Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in 2014 Long Term Procurement Plan (LTPP) and 2014-2015 California Independent System Operator (CAISO) Transmission Planning Process (TPP), issued May 6, 2014. Available at http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=90548289

[26] Two of these hours show need of less than 20 MW.

[27] Twelve month model run using the July 31, 2014 posted PLEXOS input file.

Figure 2

Capacity Headroom –2021 Retirement Scenario
Hourly Capacity Headroom, All Months, 2021



Source: Synapse modeling results, 2021 Retirement scenario based on 7/31/2014 posted CAISO model

Figure 2 accounts for units that are not available because of planned maintenance or unscheduled shutdowns. During such resource outages, the resource's "available capacity"[28] is counted as zero. The calculation of available capacity (which is a part of ORA's defined headroom metric) includes the full capacity of units in the hour after they return from an outage. However, when a unit returns from outage, its ability to provide energy or reserves at its full output level may be limited by unit commitment and unit ramping parameters in the hours

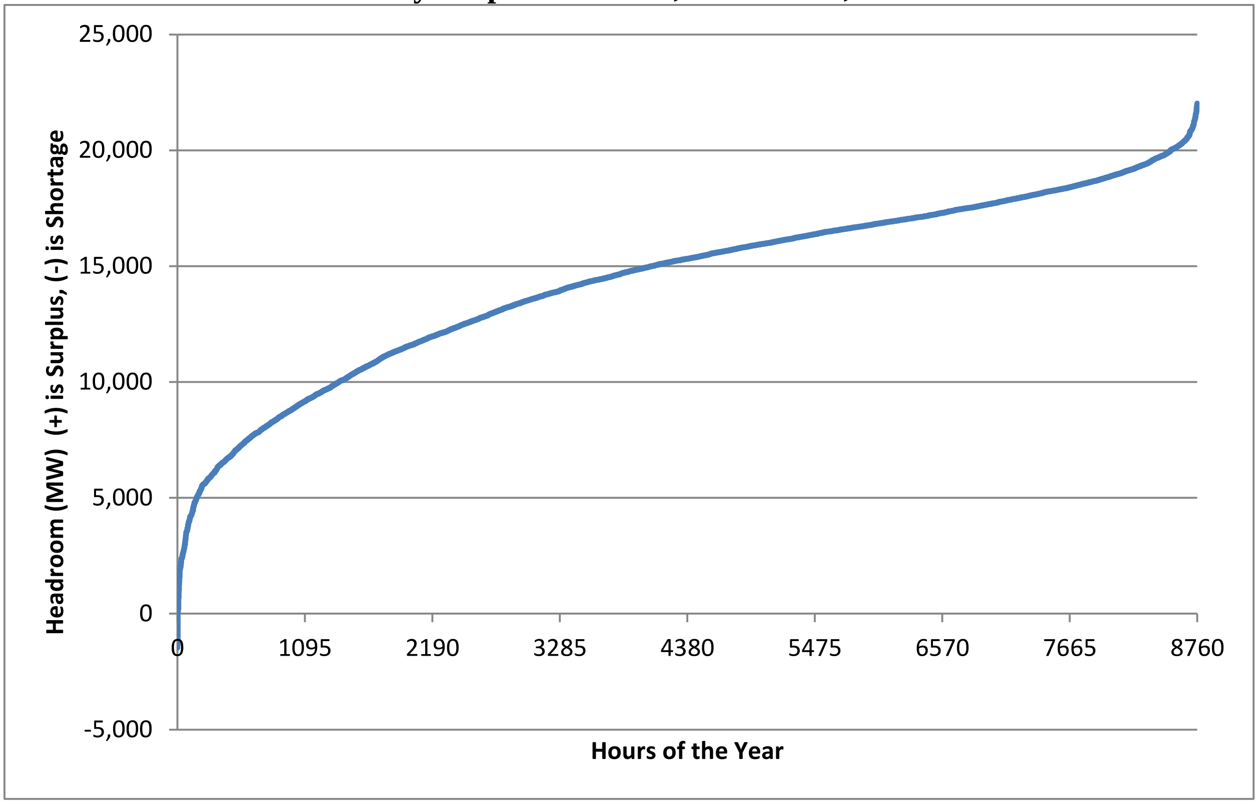
[28] Available CAISO capacity in each hour is provided in the PLEXOS file.

immediately following its return. ORA's modeling results take into account a resource's limited ability to perform immediately following its return from an outage by appropriately modifying the model's dispatch of any such units. On days with an indicated shortage, ORA's results fully account for this limited availability of a unit returning from an outage. For hours without a shortage, ORA has accounted for the effect of reduced availability in the hours immediately following a plant's return to service from an outage by adjusting the "available capacity" metric downward from the PLEXOS output. This ensures that surplus amounts in those hours are not overestimated.

As shown in Figure 2, in most hours, the CAISO region has more than sufficient capacity to meet load and ancillary service requirements, including operating reserves needed to account for the variable output of increased levels of renewable resources. Figure 2 illustrates a pattern of modeled surplus capacity for all but four hours of the year in 2021. The surplus capacity dips roughly below 5,000 MW primarily during peak periods in the months of July and August. November and December also see a number of periods where the surplus dips to or just below 5,000 MW.

Figure 3 below sorts the chronological data of Figure 2 into a duration curve. In the Retirement scenario there are a total of only four hours where the headroom dips below zero and indicates a capacity shortage.

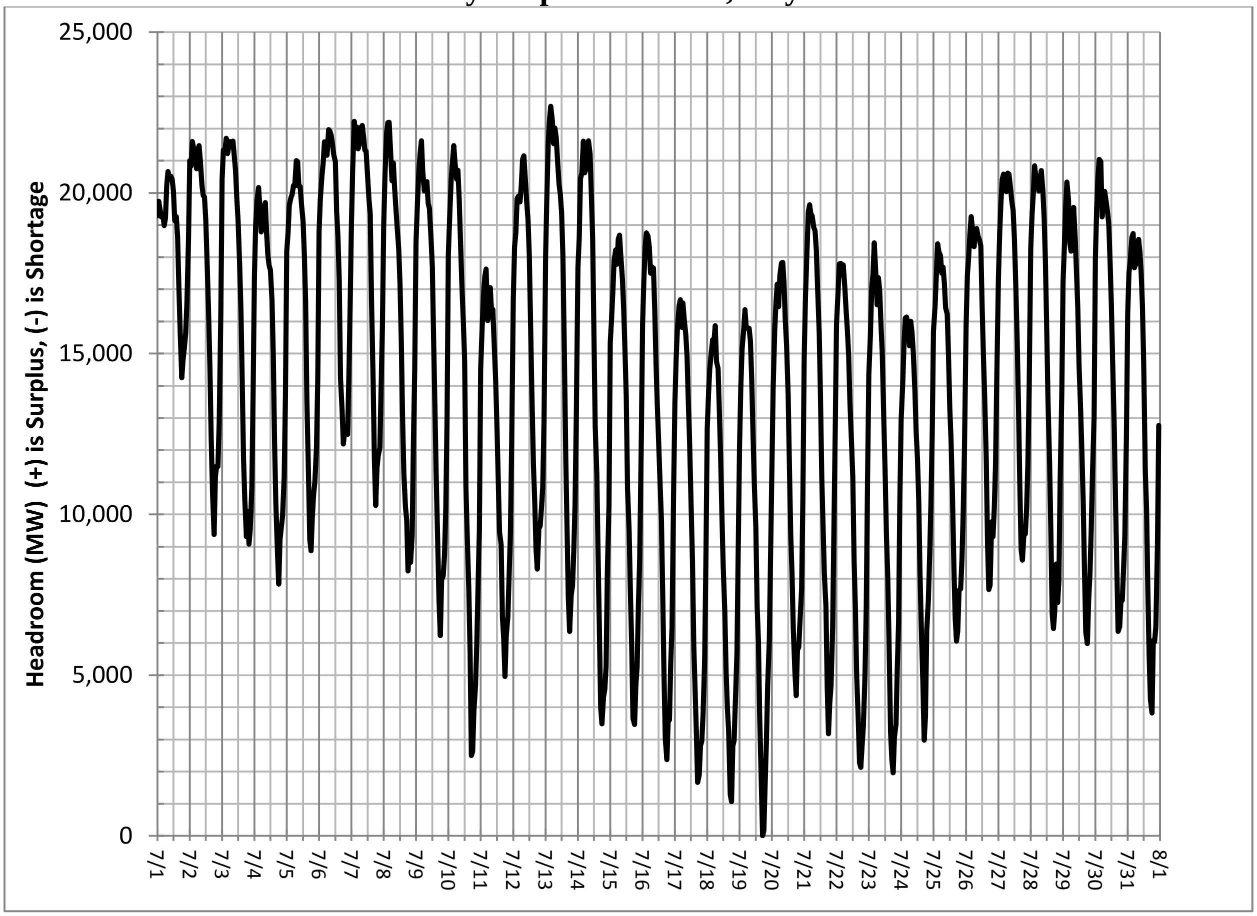
Figure 3
Duration Curve of Capacity Headroom - 2021 Retirement Scenario
Hourly Surplus/Shortfall, All Months, 2021



Source: Synapse modeling results, Retirement scenario based on 7/31/2014 posted CAISO model

As indicated in Figure 4 below, July is the month with the most significant headroom concerns, although the model run identifies no shortages under the Base case. Each of the vertical gridlines on the Figure 4 graph represents half-day (12-hour) increments.

Figure 4
Capacity Headroom – 2021 Base case Scenario
Hourly Surplus/Shortfall, July 2021



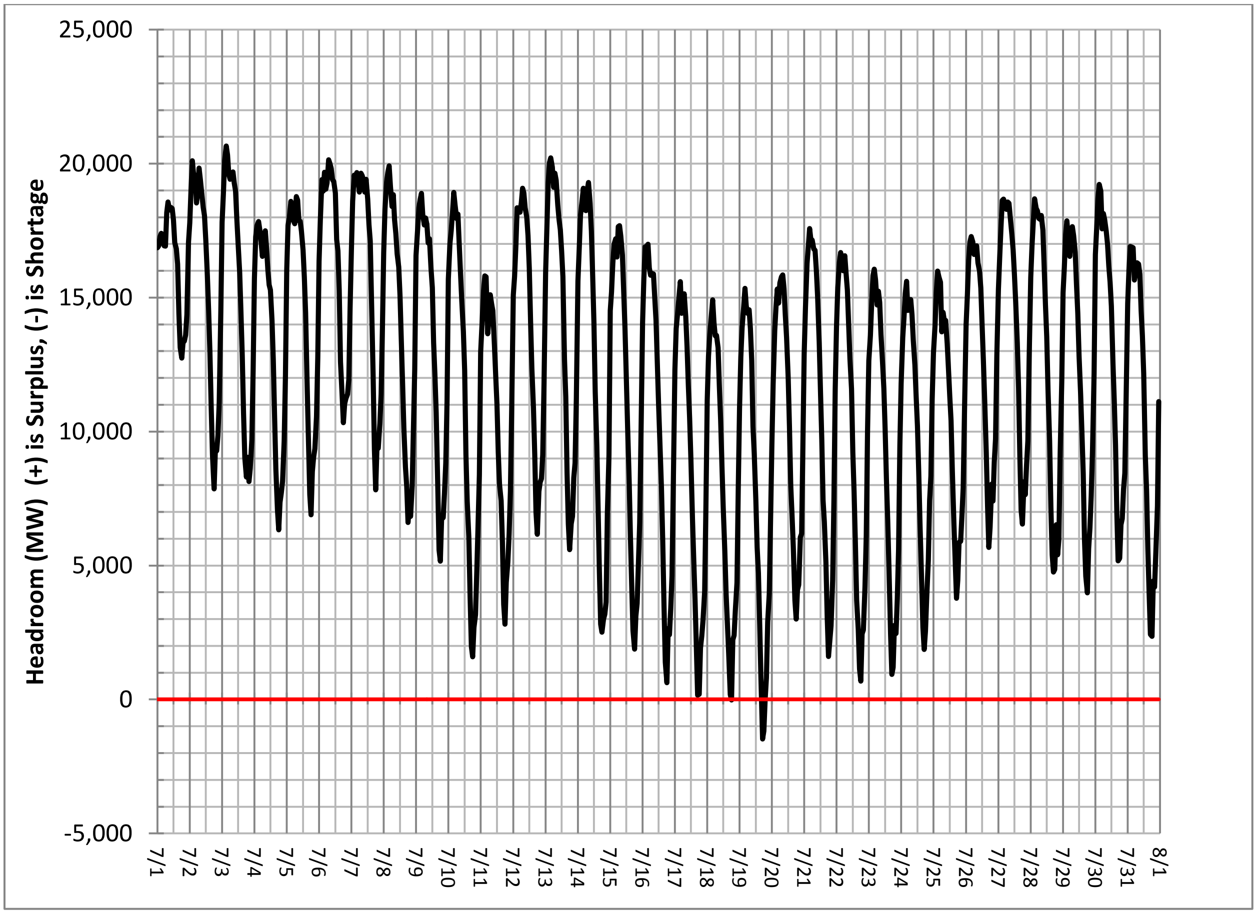
Source: Synapse modeling of 2021 Base case scenario. Note: vertical axis lined increments = 12 hours.

Figure 4 above shows the hourly pattern of capacity headroom for all hours of the month of July 2021. It demonstrates no shortage, although July 19 sees a substantial dip in available headroom.

Figures 5 shows the chronological patterns of surplus/shortage in July for the Retirement scenario. Shortages are exhibited on four hours of two peak days. Figure 5 presents the same data seen in the annual headroom graph (Figure 2), but allows for closer observation of daily and intra-day patterns in July.

Figure 5

Capacity Headroom – 2021 Retirement Scenario
Hourly Surplus/Shortfall, July 2021



Source: Synapse modeling of 2021 Retirement scenario. Note: vertical axis lined increments = 12 hours. Table 3 shows the key results for July, 2021 for the Base case and the Retirement scenarios.

Table 3
July 2021 Shortage Day Results from Base case and Retirement Scenarios Model Runs

Scenario	Shortage Duration and Period, each day	Maximum Shortage (MW) and Hour of Day	Shortage Type
2021 Base case Scenario	No shortage		
2021 Retirement Scenario	7/19, 5 p.m.	1,470 MW	LFU* & NS**
	7/19, 6 p.m.	1,173 MW	LFU
	7/19, 7 p.m.	2 MW	LFU
	7/18, 6 p.m.	17 MW	LFU

*Load following up
**Non spinning reserve
Source: Synapse modeling of Base case scenario and Retirement scenario for July, 2021.

Table 3 summarizes modeling results for the month of July 2021 for both ORA scenarios: the 2021 Base case scenario and the 2021 Retirement scenario. All other months exhibited a surplus of capacity headroom in every hour. The 2021 Base case scenario shows no shortage. The Retirement scenario shows a shortage of four hours in total over two consecutive days, July 18 and 19, 2021, exhibiting a maximum shortage of 1,470 MW at 5 p.m. on July 19.

"Shortage" does not imply a resource need. As seen in Table 3 the shortage values in the model are very infrequent and of a short duration. The "shortage" indication suggests that at this point in the procurement planning process, existing and approved resources and projected retirements do not quite deliver as much capacity as the system may need for a few hours in 2021. However, this potential conclusion depends on all the details inherent in the modeling system used, as described below.

The use of the term "shortage" in this report is limited solely to the results of the model runs executed. By itself, the term "shortage" does not directly inform or define a procurement need. In particular, additional factors besides just the "shortage" indication – e.g., including other resources not modeled, and duration of such shortages – must also be considered. The details include outage and response rates of units, transmission system import capability, limits on RPS resource deployment tied to the 33% Standard (when, in fact, additional renewable resources that result in greater than 33% RPS by 2021 are possible), maximum DR potential, and inherent load growth and net load growth assumptions.

It is likely that changes to the below fundamental input parameters over time will result in more, rather than less, resource availability to mitigate "shortages" in 2021:

- Outage rates for supply resources in the model for the critical summer peak day could decrease as California implements "flexible resource adequacy (RA)" and other ancillary service incentive structures within the CPUC RA regulatory regime and the CAISO markets. Currently, there are 2,931 MW of resources out of service in California in the Retirements case at the critical peak hour of 5 p.m. on July 19, 2021.
- As 2012 LTPP Track 4 solutions are put into place (including reactive support and new transmission upgrades), and as increased coordination is seen among WECC balancing areas,[29] maximum simultaneous transmission import levels into California or the CAISO balancing area could increase beyond what is currently modeled in the PLEXOS environment.
- Demand response (DR) potential could increase especially for infrequent load reduction that may be needed.
- The 2013 IEPR already shows a lower peak load projection for 2021 in the mid case than the 2011 IEPR showed for its 2021 mid case peak load. To the extent that load growth trends continue to change in this manner over time, residual procurement needs, if any, will decrease with each successive LTPP planning cycle, all else being equal.

ORA's modeling results reveal that in the 2021 Base case scenario, there is no system need in 2021. ORA modeling did show a shortage of 1,470 MW in 2021 under the 2021 Retirement scenario. This shortage occurs without accounting for all of the resource additions that the Commission authorized SCE and SDG&E to procure in D.13-02-015 and D.14-03-004, the LTPP Track 1 and 4 decisions. The Retirement scenario modeling results demonstrate that the CAISO region will be under the most stress during peak summer days in 2021, as in 2024.

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[29] Federal and regional initiatives are expected to improve coordination and transmission system utilization efficiencies across the western region.

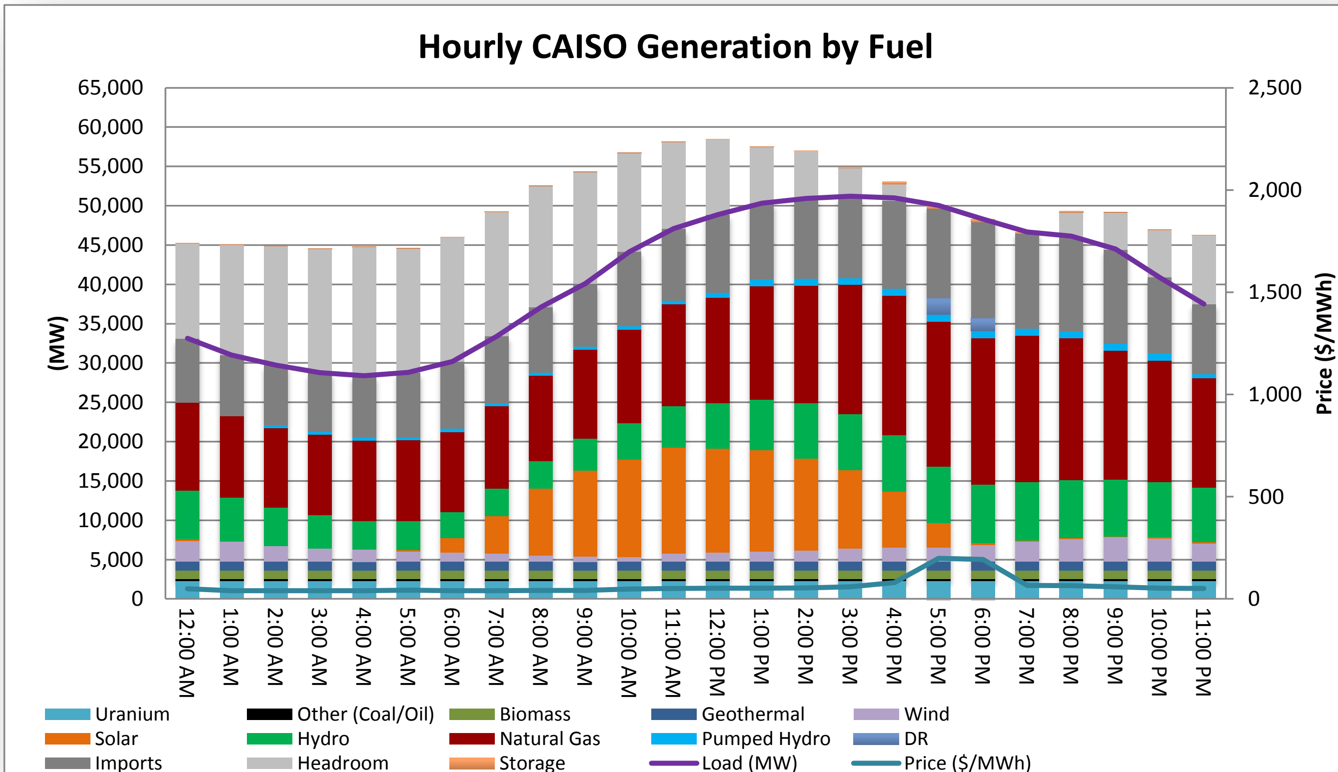
However, these results do not show a need for any additional capacity resources in the spring, fall, or winter months. In fact, surplus capacity appears abundant during all times **except** peak summer days in the late afternoon and early evening hours. A modeled capacity shortage exists for only four hours in total, which occur over two consecutive days in July during the same critical 5-8 p.m. timeframe.

ORA did not complete 2021 runs with any additional Track 1 and 4 resources, but it is very likely that the results would have been similar to results from ORA's 2024 runs in the LTPP proceeding wherein ORA did model these resources. After assuming minimum levels of authorized preferred resources in SCE and SDG&E's service territories (modeled as demand response capability), and the availability of a nominal 600 MW Gas Turbine (GT) resource in SDG&E's service territory, the model would likely have resulted in a shortage of less than 200 MW, and over no more than a single hour.

The resource output charts in Figures 6 and 7 show the 24-hour pattern of resource output in the CAISO region, aggregating individual plants to fuel type categories. Figures 6 and 7 also plot the load, the CAISO price, and computed headroom. As seen in Figure 6, the Retirement scenario's shortage duration (three hour) is reflected by the presence of only a three hour price rise to $2,000/MWh. There is positive capacity headroom on either side of the shortage hour.

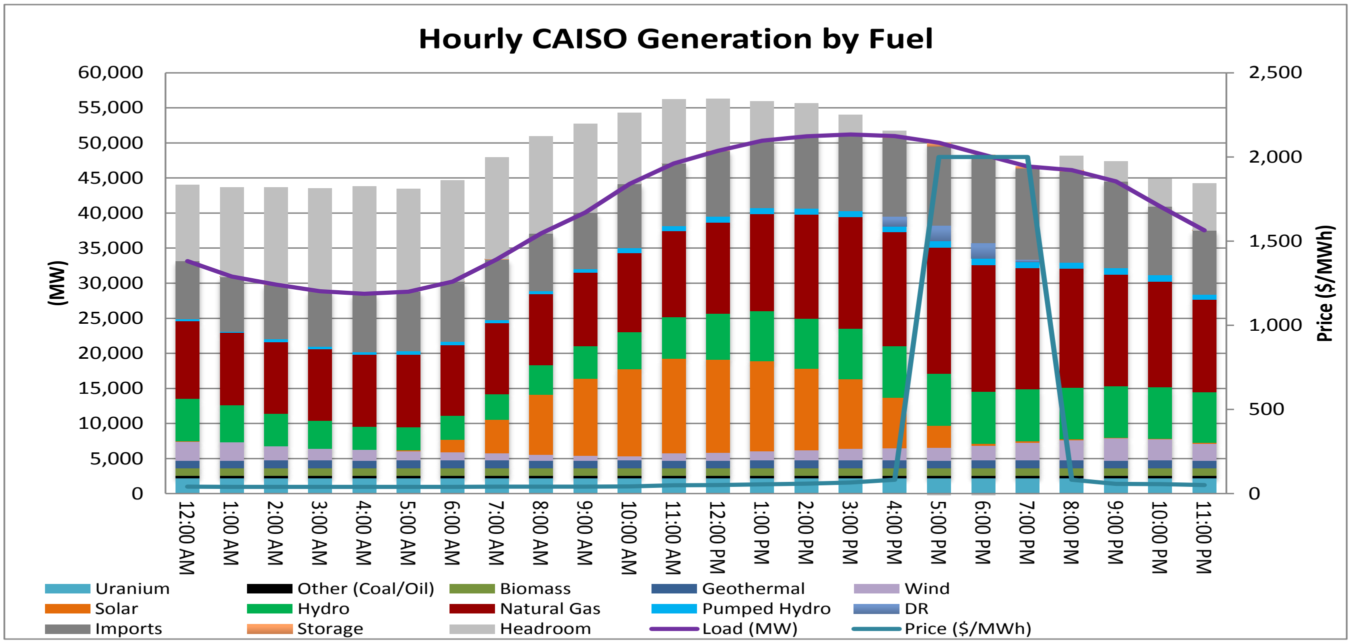
Figure 6

CAISO Region Resource Output by Hour, Peak Day (July 19, 2021)
2021 Base Case Scenario



Source: Synapse run of Base case scenario, 7/31 model, July 19.

Figure 7
CAISO Region Resource Output by Hour, Peak Day (July 19, 2021),
2021 Retirement Scenario



Source: Synapse run of 2021 Retirement scenario, 7/31 model, July 19.

Table 4 below compares the Greenhouse Gas (GHG) emissions from the results of the PLEXOS modeling for the Base case and Retirement scenarios.[30] The Retirement scenario leads to higher emissions within CAISO over the course of the month as higher emitting units replace the retired units.

[30] These results are computed for the "Need" modeling run, which uses a different set of Step 1 input values than that used for the "Production Cost" run.

Table 4
July GHG Emissions, 2021, Base case Scenario

Short Tons CO2, All months, 2021	Base Scenario	Retirement Scenario
CAISO	1,233,076	1,326,837
Rest of California	3,487,746	3,378,614
WECC Excluding California	26,513,795	26,614,494
Total WECC	**31,234,617**	**31,319,945**

Based on the duration of shortage seen in the 2021 Retirement scenario results, and considering the effect of a minimum level of additional resources already authorized by Track 1 and Track 4 LTPP decisions, there is no need for additional system reliability resource procurement at this time to reduce the risks to reliability imposed by the additional retirement of nine units accounting for 2,412 MW of NQC and 1,389 MW of EFC. Surplus capacity exists throughout the year with the exception of two days in July. These two days exhibit a shortfall in only four total hours. The maximum shortfall is 1,470 MW at 5 p.m. on July 19 as shown in Table 4.

There is surplus capacity headroom for almost all hours of the year, with only the peak load summer days showing tightness of resource availability. The projected *patterns and duration* of modeled surplus or shortage should always be considered when weighing procurement decisions, and in this instance those patterns indicate a relatively robust base of system resources, and an extremely low duration of modeled shortage. That shortage is mitigated by resources likely to be deployed as a result of the authorizations in Track 1 and Track 4, 1,325 MW at a minimum and about 2,300 MW maximum.

As in the LTPP proceeding, the modeling itself does not inform the question of timing for any resource procurement that is warranted The results of the ORA Scenarios demonstrate that including preferred resources reduces modeled shortage, indicating that the local reliability procurements authorized in Track 1 and Track 4 also benefit system reliability need. As a result, even in the unlikely event that all nine units accounting for 2,412 MW of NQC and 1,389 MW of EFC retire, the unplanned retirement would not jeopardize system reliability in 2021.

IV. ORA Conclusions

Based on this analysis, ORA concludes the following:

1. The Trajectory scenario indicates no shortage in 2021.
2. The Retirement scenario shows a shortage for only 4 hours in the peak July days of 2021, at a maximum level of 1,470 MW.
3. The addition of already authorized Track 1 and Track 4 resources are likely to result in zero modeled shortages in the Retirement scenario.

There is no indication at this time of a need to procure additional resources to reduce the risks to reliability imposed by the additional retirement of nine units accounting for 2,412 MW of NQC and 1,389 MW of EFC, given the procurement authorized in Tracks 1 and 4 of the 2012 LTPP. In other words, the unplanned retirement of up to 2,412 MW of generation resources does not appear to jeopardize system reliability.